MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED MARCH 31, 2016

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated April 26, 2016, should be read in conjunction with our March 31, 2016 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2015 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 26, 2016, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On March 31, 2016, we had a market capitalization of approximately $14 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production for the three months ended March 31, 2016 was 197,551 barrels per day and our average natural gas production was 408 MMcf per day. Our refineries processed an average of 435,000 gross barrels per day of crude oil feedstock into an average of 460,000 gross barrels per day of refined products.

Our Top Priority

The low commodity price environment has continued to significantly impact the oil and gas industry. Deterioration of crude oil prices from 2015 has resulted in further declines in our cash flow and earnings. While our balance sheet remains strong, with approximately $3.9 billion of cash on hand at March 31, 2016 and no debt maturing until the fourth quarter of 2019, we have further reduced our planned 2016 capital, operating, general and administrative spending by $400 million to $500 million, relative to our original budget. Maintaining our financial resilience continues to be our top priority, while maintaining safe operations.

Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving global prices for our products. It is based on our disciplined execution, focused innovation and our financial strength. The manufacturing approach we use to produce crude oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs, and improve productivity and efficiencies at every phase of our oil sands projects. We are focused on driving total shareholder returns.

Our integrated approach positions us to capture the full value chain from production to high-quality end products like transportation fuels. It relies on:

- Our producing asset mix, including:
  - Oil sands for long-term growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will position us to achieve the best pricing for our oil.

We have adopted a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

Oil Development

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids, as well as our conventional oil opportunities.

We are positioned to increase our annual net crude oil production, including our conventional crude oil operations, by fully developing our producing projects and those that currently have regulatory approval.

Disciplined Manufacturing

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, positioning us to minimize costs. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date. We are committed to developing our resources safely and responsibly.

Financial Strength

Maintaining a strong balance sheet is necessary to execute our strategy. We anticipate our total annual capital investment for 2016 to be between $1.2 billion and $1.3 billion. This is 27 percent lower than in 2015, reflecting moderate spending in response to the sustained low commodity price environment. At March 31, 2016, we had $3.9 billion of cash on hand, $4.0 billion of undrawn capacity on our committed credit facility, and no debt maturing until the fourth quarter of 2019. To help preserve our continued financial resilience, we will pursue further cost reductions, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

In the first quarter, we paid a dividend of $0.05 per share or $41 million. This is a 69 percent reduction from our dividend of $0.16 per share in the fourth quarter of 2015. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

Focused Innovation

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing technologies with a focus on increasing recoveries from our reservoirs, and improving cycle times, margins and environmental performance. We have a track record of developing innovative solutions that unlock challenging crude oil resources, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Our Operations

Oil Sands

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Three Months Ended March 31, 2016		
	Ownership Interest (percent)	**Net Production Volumes** (bbls/d)	**Gross Production Volumes** (bbls/d)
Existing Projects			
Foster Creek	**50**	**60,882**	**121,764**
Christina Lake	**50**	**77,093**	**154,186**
Narrows Lake	**50**	**-**	**-**
Emerging Projects			
Telephone Lake	**100**	**-**	**-**
Grand Rapids	**100**	**-**	**-**

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. Foster Creek and Christina Lake are producing and Narrows Lake is in the initial stages of development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent-owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions of northeastern Alberta, respectively.

	Three Months Ended March 31, 2016	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Cash Flow	**45**	**1**
Capital Investment	**227**	**-**
Operating Cash Flow Net of Related Capital Investment	**(182)**	**1**

Conventional

Crude oil production from our Conventional business segment continues to generate dependable near-term cash flows. This production provides diversification to our revenue stream and enables further development of our oil sands assets. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations and provides cash flow to help fund our growth opportunities.

	Three Months Ended March 31, 2016	
($ millions)	**Crude Oil (1)**	**Natural Gas**
Operating Cash Flow	**88**	**33**
Capital Investment	**37**	**2**
Operating Cash Flow Net of Related Capital Investment	**51**	**31**

(1) *Includes NGLs.*

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("CO_2") enhanced oil recovery project in Weyburn, Saskatchewan, and emerging tight oil assets in Alberta.

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. The Wood River and Borger refineries have a gross crude oil capacity of approximately 314,000 barrels per day and 146,000 barrels per day, respectively.

Our refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations. This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	**Three Months Ended March 31, 2016**
Operating Cash Flow	**(23)**
Capital Investment	**52**
Operating Cash Flow Net of Related Capital Investment	**(75)**

QUARTERLY HIGHLIGHTS

Average crude oil benchmark prices continued to decline in the first quarter of 2016, decreasing between 21 and 31 percent compared with the fourth quarter of 2015, and we are undertaking additional measures to help preserve our financial resilience.

In the first quarter, we:

- Realized Operating Losses of $423 million or $17.38 per barrel of crude oil equivalent sold;
- Incurred a Cash Flow shortfall before realized risk management activities of $96 million;
- Realized gains of $6.08 per barrel of crude oil equivalent sold from upstream risk management activities;
- Decreased our total crude oil operating costs by 20 percent or $49 million, compared with 2015;
- Identified additional workforce reductions in the first quarter, which were largely implemented in early April, which will result in an 11 percent reduction from our workforce at December 31, 2015; and
- Recorded inventory and asset impairments of $31 million and $170 million, respectively, due to a decline in commodity prices.

In February, we announced plans to reduce our 2016 capital, operating, general and administrative spending by $400 million to $500 million, relative to our original 2016 budget. Capital spending across our operations is planned to be between $1.2 billion and $1.3 billion, a reduction of $200 million to $300 million. Operating and general and administrative cost savings of $200 million are anticipated through further prioritization of repairs and maintenance, the cancellation or deferral of non-essential work, and workforce reductions. We also reduced our dividend to $0.05 per share in the first quarter of 2016.

OPERATING RESULTS

Crude oil production from our Oil Sands segment and Conventional properties declined in the first quarter of 2016.

Crude Oil Production Volumes

	Three Months Ended March 31,		
(barrels per day)	**2016**	**Percent Change**	2015
Oil Sands			
Foster Creek	**60,882**	**(10)%**	67,901
Christina Lake	**77,093**	**1%**	76,471
	137,975	**(4)%**	144,372
Conventional			
Heavy Oil	**31,247**	**(16)%**	37,155
Light and Medium Oil	**27,121**	**(23)%**	35,135
NGLs [(1)]	**1,208**	**(11)%**	1,358
	59,576	**(19)%**	73,648
Total Crude Oil Production	**197,551**	**(9)%**	218,020

(1) NGLs include condensate volumes.

At Foster Creek, our surface facilities (steam and fluid handling) continue to perform well, constrained only by lower production from the field. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which, combined with the faster declines, contributed to lower production compared with the first quarter of 2015. In addition, a higher than average number of wells were down for servicing during the quarter, which further impacted production. We increased workover activity in 2016 and have started bringing some of these wells back online.

Production from Christina Lake increased slightly compared with the first quarter of 2015 due to additional wells and reliable performance of our facilities.

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,700 barrels per day in the first quarter of 2015.

Natural Gas Production Volumes

	Three Months Ended March 31,	
(MMcf per day)	**2016**	2015
Conventional	**391**	442
Oil Sands	**17**	20
	408	462

Our natural gas production declined 12 percent compared with the first quarter of 2015. Production decreased primarily due to expected natural declines, and the sale of our royalty interest and mineral fee title lands business, which produced 19 MMcf per day during the first quarter of 2015.

Operating Netbacks

	Crude Oil [1] ($/bbl)		**Natural Gas** ($/Mcf)	
	Three Months Ended March 31,			
	2016	2015	**2016**	2015
Price [2]	**15.97**	31.08	**2.31**	3.05
Royalties	**0.92**	1.16	**0.09**	0.05
Transportation and Blending [2]	**5.85**	5.31	**0.10**	0.12
Operating Expenses [3]	**11.08**	12.89	**1.23**	1.26
Production and Mineral Taxes	**0.11**	0.22	**-**	0.01
Netback Excluding Realized Risk Management [4]	**(1.99)**	11.50	**0.89**	1.61
Realized Risk Management Gain (Loss)	**8.16**	6.58	**-**	0.29
Netback Including Realized Risk Management	**6.17**	18.08	**0.89**	1.90

(1) Includes NGLs.
(2) The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate was $20.06 per barrel (2015 – $22.29 per barrel).
(3) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(4) The netbacks do not reflect non-cash write-downs of product inventory.

Our average crude oil netback for the first quarter of 2016, excluding realized risk management gains and losses, was negative primarily due to lower sales prices, consistent with the decline in benchmark prices and stable heavy oil differentials. Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark resulting from inventory timing in a falling price environment and transportation between market hubs and field locations.

The weakening of the Canadian dollar compared with the first quarter of 2015 had a positive impact on our crude oil price of approximately $1.54 per barrel.

Our average natural gas netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices, consistent with the decline in the AECO benchmark price.

Refining

Crude oil runs decreased slightly compared with 2015, although higher heavy crude oil volumes were processed due to the optimization of our total crude input slate. In the first quarter of 2016, we completed planned and unplanned maintenance at our Wood River and Borger refineries. In the first quarter of 2015, a planned turnaround was completed at our Borger Refinery.

	Three Months Ended March 31,		
	2016	Percent Change	2015
Crude Oil Runs [1] (Mbbls/d)	**435**	**(1)%**	439
Heavy Crude Oil [1]	**241**	**10%**	220
Refined Product [1] (Mbbls/d)	**460**	**(2)%**	469
Crude Utilization [1] (percent)	**95**	**-**	95

(1) Represents 100 percent of the Wood River and Borger refinery operations.

Operating Cash Flow from Refining and Marketing in the first quarter of 2016 was a shortfall of $23 million, primarily due to lower average market crack spreads and higher operating costs, partially offset by weakening of the Canadian dollar relative to the U.S. dollar.

Further information on the changes in our production volumes, items included in our operating netbacks and refining results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and the U.S./Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [1]

	Q1 2016	Percent Change	Q1 2015	Q4 2015
Crude Oil Prices (US$/bbl)				
Brent				
Average	**35.08**	**(36)%**	55.17	44.71
End of Period	**39.60**	**(28)%**	55.11	37.28
WTI				
Average	**33.45**	**(31)%**	48.63	42.18
End of Period	**38.34**	**(19)%**	47.60	37.04
Average Differential Brent-WTI	**1.63**	**(75)%**	6.54	2.53
WCS [2]				
Average	**19.21**	**(43)%**	33.90	27.69
End of Period	**26.75**	**(28)%**	37.30	24.98
Average Differential WTI-WCS	**14.24**	**(3)%**	14.73	14.49
Condensate (C5 @ Edmonton) [3]				
Average	**34.39**	**(25)%**	45.62	41.67
Average Differential WTI-Condensate (Premium)/Discount	**(0.94)**	**(131)%**	3.01	0.51
Average Differential WCS-Condensate (Premium)/Discount	**(15.18)**	**30%**	(11.72)	(13.98)
Average Refined Product Prices (US$/bbl)				
Chicago Regular Unleaded Gasoline (“RUL”)	**42.00**	**(33)%**	62.45	55.24
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**44.55**	**(37)%**	70.33	59.23
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)				
Chicago	**9.58**	**(42)%**	16.53	14.47
Group 3	**10.52**	**(40)%**	17.46	13.82
Average Natural Gas Prices				
AECO (C$/Mcf)	**2.11**	**(28)%**	2.95	2.65
NYMEX (US$/Mcf)	**2.09**	**(30)%**	2.98	2.27
Basis Differential NYMEX-AECO (US$/Mcf)	**0.56**	**(2)%**	0.57	0.27
Foreign Exchange Rates (US$ per C$1)				
Average	**0.728**	**(10)%**	0.806	0.749

(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.
(2) The average Canadian dollar WCS benchmark price for the first quarter of 2016 was $26.39 per barrel (2015 – $42.06 per barrel).
(3) The average Canadian dollar condensate benchmark price for the first quarter of 2016 was $47.24 per barrel (2015 – $56.60 per barrel).

Crude Oil Benchmarks

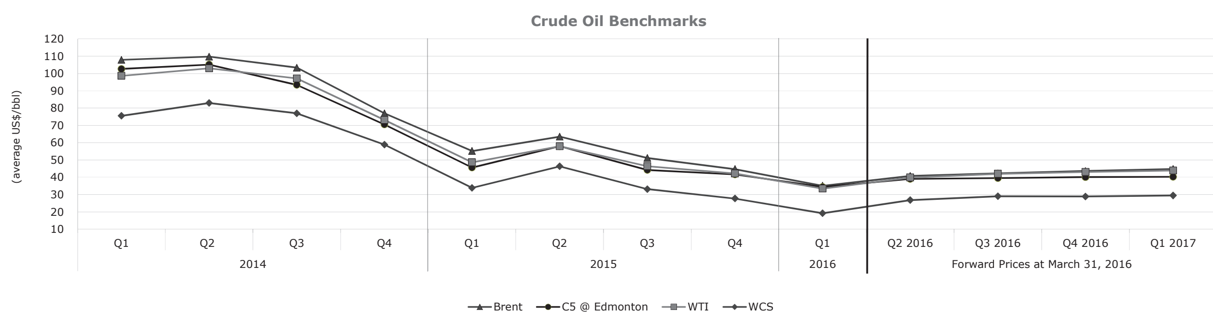
The average Brent, WTI and WCS benchmark prices continued to be impacted by the global imbalance of supply and demand which began in the second half of 2014. This imbalance, created by weak global demand for oil and strong growth in North American crude oil supply, was further amplified by the decision of the Organization of Petroleum Exporting Countries (“OPEC”) to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Some OPEC and non-OPEC members discussed the possibility of a freeze in production, although at relatively high levels. However, a formal agreement was not reached as Saudi Arabia has stated it will not freeze production without Iran's participation. The current price environment, which is slowing U.S. supply growth, is gradually improving the global oil imbalance of supply and demand. However, economic uncertainty in China, continued strong production from Saudi Arabia and Iraq, as well as concerns regarding the return of Iranian production are expected to limit near-term price increases.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed compared with the first quarter of 2015. WTI benchmark prices strengthened relative to Brent as a result of high global crude oil inventory levels, declining U.S. supply and the lifting of the U.S. export ban, leaving transportation costs as the primary driver of the Brent-WTI differential. As a result, we believe both Brent and WTI are currently indicative of inland refined product prices.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed only slightly from the first quarter of 2015, despite the steep decline in the WTI and WCS benchmark prices from the ongoing global oil imbalance of supply and demand. This imbalance has also resulted in higher global imports of medium and heavy crude into North American markets, which has in turn, further reduced WCS prices.

Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost attributed to transporting the condensate to Edmonton.

Average condensate prices exceeded the WTI benchmark price in the first quarter of 2016 in contrast to condensate being sold at a discount to WTI in the first quarter of 2015. Strong condensate prices are attributable to higher seasonal diluent demand during winter months coupled with strong gasoline demand in North America.

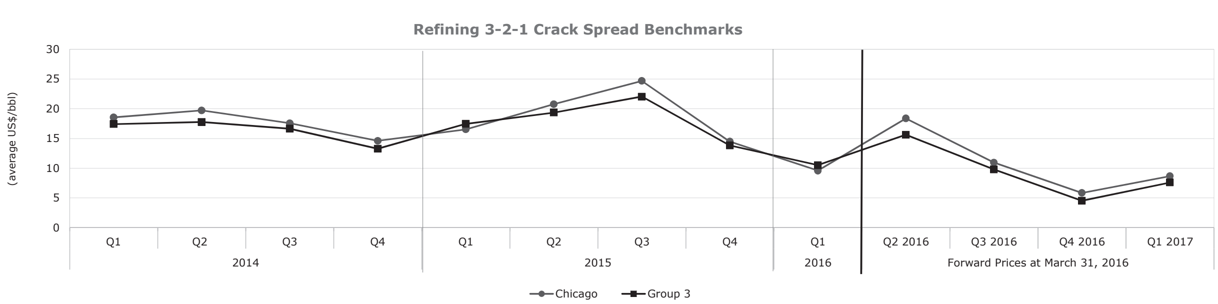


Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 crack spread. The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI-based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago 3-2-1 crack spreads and Group 3 crack spreads decreased in the first quarter of 2016 compared with 2015 due to higher global refined product inventory and the narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock, which is valued on a first in, first out ("FIFO") accounting basis.



Natural Gas Benchmarks

Average natural gas prices decreased in 2016 primarily due to increased supply from the U.S. and Canada.

Foreign Exchange Benchmarks

Revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the first quarter of 2016, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and the expectation of higher U.S. interest rates in the future. The weakening of the Canadian dollar, compared with the first quarter of 2015, had a positive impact of approximately $216 million on our revenues. As at March 31, 2016, the Canadian dollar was stronger relative to the U.S. dollar than as at December 31, 2015, which resulted in $413 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

Sustained low commodity prices in the first quarter of 2016 significantly impacted our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	2016	2015				2014			
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	**2,245**	2,924	3,273	3,726	3,141	4,238	4,970	5,422	5,012
Operating Cash Flow (1)(2)	**144**	357	602	932	548	537	1,156	1,305	1,181
Cash Flow (1)	**26**	275	444	477	495	401	985	1,189	904
Per Share – Diluted	**0.03**	0.33	0.53	0.58	0.64	0.53	1.30	1.57	1.19
Operating Earnings (Loss) (1)	**(423)**	(438)	(28)	151	(88)	(590)	372	473	378
Per Share – Diluted	**(0.51)**	(0.53)	(0.03)	0.18	(0.11)	(0.78)	0.49	0.62	0.50
Net Earnings (Loss)	**(118)**	(641)	1,801	126	(668)	(472)	354	615	247
Per Share – Basic	**(0.14)**	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47	0.81	0.33
Per Share – Diluted	**(0.14)**	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47	0.81	0.33
Capital Investment (3)	**323**	428	400	357	529	786	750	686	829
Dividends									
Cash Dividends	**41**	132	133	125	138	201	201	201	202
In Shares from Treasury	**-**	-	-	98	84	-	-	-	-
Per Share	**0.05**	0.16	0.16	0.2662	0.2662	0.2662	0.2662	0.2662	0.2662

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

Revenues

($ millions)	
Revenues for the Three Months Ended March 31, 2015	**3,141**
Increase (Decrease) due to:	
Oil Sands	**(259)**
Conventional	**(168)**
Refining and Marketing	**(508)**
Corporate and Eliminations	**39**
Revenues for the Three Months Ended March 31, 2016	**2,245**

Combined Oil Sands and Conventional revenues declined 37 percent in the first quarter of 2016 due to lower commodity prices and reduced sales volumes, partially offset by weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues. These declines were partially offset by lower royalties.

Revenues from our Refining and Marketing segment decreased 24 percent from 2015. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in

2016 decreased 18 percent from 2015, primarily due to a decline in sales prices and purchased crude oil volumes, partially offset by an increase in purchased natural gas volumes.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

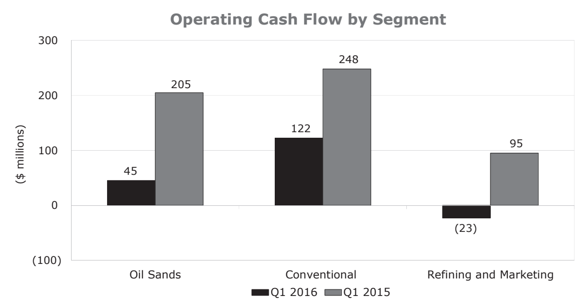
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

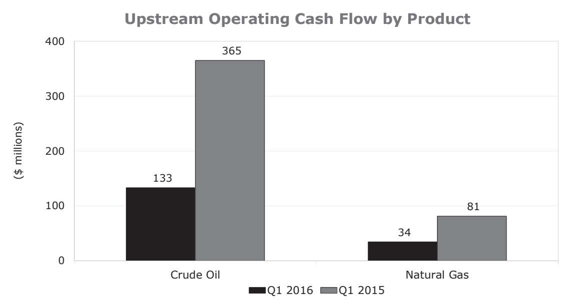
Operating Cash Flow

Operating Cash Flow is a non-GAAP measure used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

	Three Months Ended March 31,	
($ millions)	**2016**	2015
Revenues	**2,312**	3,247
(Add) Deduct:		
Purchased Product	**1,428**	1,838
Transportation and Blending	**451**	528
Operating Expenses [1]	**452**	479
Production and Mineral Taxes	**2**	5
Realized (Gain) Loss on Risk Management Activities	**(165)**	(151)
Operating Cash Flow	**144**	548

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.





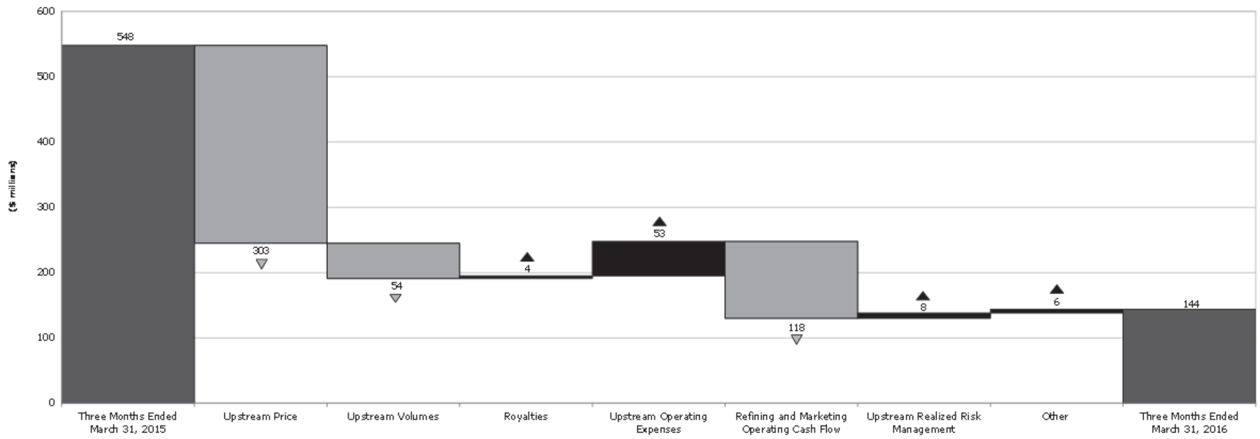
Operating Cash Flow declined 74 percent in the first quarter of 2016 primarily due to:

- A 49 percent decrease in our average crude oil sales price and a 24 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- An eight percent decline in our crude oil sales volumes as well as a 12 percent decline in natural gas sales volumes; and
- Lower Operating Cash Flow from Refining and Marketing as a result of lower average market crack spreads and higher operating costs, partially offset by weakening of the Canadian dollar relative to the U.S. dollar.

These declines in Operating Cash Flow were partially offset by:

- A $75 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes; and
- A $49 million decrease in crude oil operating expenses primarily due to our workforce reductions undertaken in 2015, lower chemical costs, repairs and maintenance activities, and workover activities.

Operating Cash Flow Variance



Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

Cash Flow

Cash Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Cash Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

	Three Months Ended March 31,	
($ millions)	**2016**	2015
Cash From Operating Activities	**182**	275
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(29)**	(54)
Net Change in Non-Cash Working Capital	**185**	(166)
Cash Flow	**26**	495

In the first quarter of 2016, Cash Flow decreased due to a combination of lower Operating Cash Flow, as discussed above, and a lower current income tax recovery.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

	Three Months Ended March 31,	
($ millions)	**2016**	2015
Earnings (Loss), Before Income Tax	**(335)**	(781)
Add (Deduct):		
Unrealized Risk Management (Gain) Loss (1)	**149**	145
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**(413)**	514
(Gain) Loss on Divestiture of Assets	**-**	(16)
Operating Earnings (Loss), Before Income Tax	**(599)**	(138)
Income Tax Expense (Recovery)	**(176)**	(50)
Operating Earnings (Loss)	**(423)**	(88)

(1) *Includes the reversal of unrealized (gains) losses recorded in prior periods.*
(2) *Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.*

Operating Earnings decreased compared with the same period in 2015 primarily due to lower Cash Flow and higher depreciation, depletion and amortization ("DD&A") as a result of asset impairments, partially offset by a deferred income tax recovery.

Net Earnings

($ millions)	
Net Earnings (Loss) for the Three Months Ended March 31, 2015	**(668)**
Increase (Decrease) due to:	
Operating Cash Flow [1] [2]	**(404)**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**(4)**
Unrealized Foreign Exchange Gain (Loss)	**932**
Gain (Loss) on Divestiture of Assets	**(16)**
Expenses [2] [3]	**(18)**
Depreciation, Depletion and Amortization	**(43)**
Exploration Expense	**(1)**
Income Tax Recovery	**104**
Net Earnings (Loss) for the Three Months Ended March 31, 2016	**(118)**

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

In 2016, our Net Earnings increased primarily due to non-operating unrealized foreign exchange gains of $413 million (2015 – unrealized losses of $514 million), partially offset by a decline in Operating Earnings, as discussed above.

Net Capital Investment

	Three Months Ended March 31,	
($ millions)	**2016**	2015
Oil Sands	**227**	414
Conventional	**39**	66
Refining and Marketing	**52**	44
Corporate and Eliminations	**5**	5
Capital Investment	**323**	529
Divestitures	**-**	(16)
Net Capital Investment [1]	**323**	513

(1) Includes expenditures on PP&E and E&E.

Capital investment in the first quarter of 2016 declined 39 percent as we reduced our spending in light of the low commodity price environment.

Oil Sands capital investment focused primarily on sustaining capital related to existing production, the phase G expansion at Foster Creek, and the Christina Lake expansion phase F. We drilled 192 gross stratigraphic test wells at Foster Creek and Christina Lake to determine pad placement for sustaining wells and near-term expansion phases. Conventional capital investment focused on maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn.

Capital investment in the Refining and Marketing segment focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives.

Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital.

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria within the context of achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position us to be financially resilient in times of lower cash flow. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	Three Months Ended March 31, 2016	2015
Cash Flow [1]	**26**	495
Capital Investment (Committed and Growth)	**323**	529
Free Cash Flow [2]	**(297)**	(34)
Cash Dividends	**41**	138
	(338)	(172)

(1) Non-GAAP measure defined in this MD&A.
(2) Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.

We expect our capital investment for 2016 to be funded from internally generated cash flow and our cash balance on hand.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of Cenovus's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

Refining and Marketing, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

Revenues by Reportable Segment

($ millions)	Three Months Ended March 31, 2016	2015
Oil Sands	**470**	729
Conventional	**254**	422
Refining and Marketing	**1,588**	2,096
Corporate and Eliminations	**(67)**	(106)
	2,245	3,141

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of development, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant developments in our Oil Sands segment include:

- Negative crude oil netbacks, excluding realized risk management activities, of $6.10 per barrel;
- Production at Foster Creek decreasing 10 percent to an average of 60,882 barrels per day as strong facility performance was offset by lower field production;
- Reducing our crude oil operating costs by $17 million or $1.47 per barrel; and
- Reducing capital investment by $187 million compared with 2015.

Oil Sands – Crude Oil

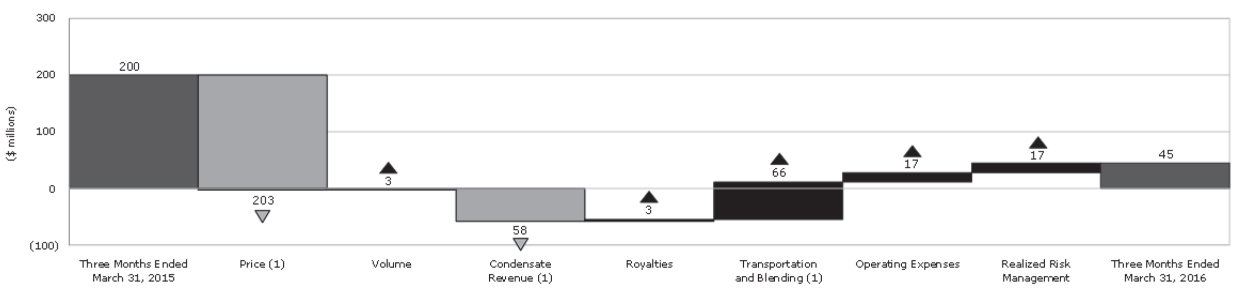
Financial Results

	Three Months Ended March 31,	
($ millions)	**2016**	2015
Gross Sales	**465**	723
Less: Royalties	**-**	3
Revenues	**465**	720
Expenses		
Transportation and Blending	**404**	470
Operating [(1)]	**122**	139
(Gain) Loss on Risk Management	**(106)**	(89)
Operating Cash Flow	**45**	200
Capital Investment	**227**	413
Operating Cash Flow Net of Related Capital Investment	**(182)**	(213)

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

Operating Cash Flow Variance



(1) *Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

Revenues

Pricing

In the first quarter, our average crude oil sales price was $10.13 per barrel, a 61 percent decrease from 2015. The decline in our crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices. Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark resulting from inventory timing in a falling price environment and transportation between market hubs and field locations. Weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market, which generally secure a higher sales price, positively impacted our realized sales prices.

The WCS-CDB differential narrowed by 39 percent to a discount of US$1.96 per barrel (2015 – US$3.21 per barrel). In the first quarter, 90 percent of our Christina Lake production was sold as CDB (2015 – 86 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	Three Months Ended March 31, 2016	Percent Change	2015
Foster Creek	**60,882**	**(10)%**	67,901
Christina Lake	**77,093**	**1%**	76,471
	137,975	**(4)%**	144,372

At Foster Creek, our surface facilities (steam and fluid handling) continue to perform well constrained only by lower production from the field. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which, combined with the faster declines, contributed to lower production compared with the first quarter of 2015. In addition, a higher than average number of wells were down for servicing during the quarter, which further impacted production. We increased workover activity in 2016 and have started bringing some of these wells back online.

Production from Christina Lake increased slightly compared with the first quarter of 2015 due to additional wells and consistent performance of our facilities.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate.

Royalties

Royalty calculations for our oil sands projects are based on government prescribed pre- and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price. Royalty calculations differ between properties.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Effective Royalty Rates

(percent)	Three Months Ended March 31, 2016	2015
Foster Creek	**(4.9)**	(1.2)
Christina Lake	**1.2**	3.1

Royalties decreased primarily due to the decline in crude oil sales prices. At Foster Creek, low crude oil sales prices and the true-up of the 2015 royalty calculation resulted in a negative royalty rate for the first quarter of 2016. In the first quarter of 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation for Foster Creek. We recorded the associated credit in the first quarter of 2015, which resulted in a negative royalty rate. Excluding the credit, the effective royalty rate for Foster Creek would have been 5.9 percent in the first quarter of 2015.

The Christina Lake royalty rate decreased in the first quarter as a result of lower sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $66 million or 14 percent. Blending costs declined primarily as a result of lower condensate prices partially offset by higher condensate volumes from increased production at Christina Lake. Our condensate costs were higher than the average benchmark price in the first quarter, primarily due to the utilization of higher priced inventory and the transportation expense associated with moving the condensate to our oil sands projects. In the first quarter of 2016, we recorded a $25 million, or $2.00 per barrel of oil sold, (2015 – $nil) write-down of our blended crude oil inventory to net realizable value as a result of the decline in crude oil prices through March and into April.

Transportation costs increased primarily due to higher pipeline tariffs and higher tariffs from additional sales to the U.S. market, which generally secure higher sales prices, partially offset by lower rail costs. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

Lower volumes were moved by rail in the first quarter of 2016. We transported an average of 4,627 gross barrels per day of crude oil by rail, consisting of seven unit train shipments (2015 – 11,871 gross barrels per day, 18 unit train shipments). The seven unit trains were loaded at our crude-by-rail terminal operations, located in Bruderheim, Alberta.

Operating

Primary drivers of our operating expenses for the first quarter were workforce, fuel, workovers, repairs and maintenance and chemical costs. Total operating expenses decreased $17 million or $1.47 per barrel primarily as a result of workforce reductions, lower natural gas prices that reduced fuel costs and lower repairs and maintenance activities.

Per-unit Operating Expenses

	Three Months Ended March 31,		
($/bbl)	**2016**	**Percent Change**	2015
Foster Creek			
Fuel	**2.48**	**(16)%**	2.96
Non-fuel [1]	**9.57**	**(17)%**	11.54
Total	**12.05**	**(17)%**	14.50
Christina Lake			
Fuel	**1.96**	**(11)%**	2.19
Non-fuel [1]	**5.65**	**(7)%**	6.05
Total	**7.61**	**(8)%**	8.24
Total	**9.52**	**(13)%**	10.99

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

At Foster Creek, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined primarily due to:

- Lower workforce costs due to our more moderate approach to oil sands expansions;
- Lower repairs and maintenance costs due to a focus on critical operational activities; and
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes.

The decreases to non-fuel operating costs at Foster Creek were partially offset by lower production volumes.

At Christina Lake, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased primarily due to:

- Increased production;
- Lower workforce costs due to our more moderate approach to oil sands expansions; and
- Lower chemical costs due to supply chain initiatives.

These decreases to non-fuel operating costs at Christina Lake were partially offset by higher well workover activities related to additional pump changes.

Operating Netbacks

	Foster Creek		Christina Lake	
	Three Months Ended March 31,			
($/bbl)	**2016**	2015	**2016**	2015
Price [1]	**11.82**	29.42	**8.85**	23.30
Royalties	**(0.16)**	(0.25)	**0.05**	0.61
Transportation and Blending [1]	**8.70**	9.39	**5.28**	4.17
Operating Expenses [2]	**12.05**	14.50	**7.61**	8.24
Netback Excluding Realized Risk Management [3]	**(8.77)**	5.78	**(4.09)**	10.28
Realized Risk Management	**9.49**	8.41	**7.43**	6.04
Netback Including Realized Risk Management	**0.72**	14.19	**3.34**	16.32

(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in the first quarter was $26.13 per barrel (2015 – $30.57 per barrel) for Foster Creek, and $26.45 per barrel (2015 – $31.60 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

(2) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

(3) *The netbacks do not reflect non-cash write-downs of product inventory.*

Risk Management

Risk management activities in the first quarter of 2016 resulted in realized gains of $106 million (2015 – $89 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for the first quarter of 2016, net of internal usage, was 17 MMcf per day (2015 – 20 MMcf per day). Operating Cash Flow was $1 million (2015 – $3 million), declining primarily due to lower natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended March 31, 2016	2015
Foster Creek	**89**	149
Christina Lake	**114**	207
	203	356
Narrows Lake	**4**	20
Telephone Lake	**7**	11
Grand Rapids	**5**	14
Other (1)	**8**	13
Capital Investment (2)	**227**	414

(1) Includes new resource plays and Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

In the first quarter, capital investment exceeded Operating Cash Flow by $182 million (2015 – $209 million) and was funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

Existing Projects

Capital investment at Foster Creek focused on sustaining capital related to existing production, expansion phase G and drilling stratigraphic test wells to help identify well pad locations for sustaining wells and near-term expansion phases. Capital investment declined in the current quarter primarily due to spending reductions in response to the low commodity price environment.

Christina Lake capital investment focused on sustaining capital related to existing production, expansion phase F and drilling stratigraphic test wells to help identify well pad locations for sustaining wells and near-term expansion phases. Capital investment decreased due to the completion of the optimization project in 2015 and overall spending reductions.

Capital investment at Narrows Lake focused on detailed engineering. Capital investment declined in 2016 compared with 2015 due to the suspension of construction at Narrows Lake.

Emerging Projects

In the first quarter of 2016, Telephone Lake capital investment declined in response to the current low commodity price environment. In the first quarter of 2015, Telephone Lake capital investment focused on front-end engineering work for the central processing facility.

Capital investment at Grand Rapids decreased as spending was limited to the wind down of the SAGD pilot. In the first quarter of 2015, a third pilot well pair was drilled at Grand Rapids.

Drilling Activity (1)

	Gross Stratigraphic Test Wells (2)		Gross Production Wells (3)	
Three Months Ended March 31,	**2016**	2015	**2016**	2015
Foster Creek	**95**	122	**4**	13
Christina Lake	**97**	36	**18**	19
	192	158	**22**	32
Grand Rapids	**-**	-	**-**	1
Other	**5**	-	**-**	-
	197	158	**22**	33

(1) We did not drill any gross service wells in the first quarter of 2016 (2015 – five gross service wells).
(2) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In the first quarter, no wells were drilled using our SkyStrat™ drilling rig (2015 – seven wells).
(3) SAGD well pairs are counted as a single producing well.

Future Capital Investment

We have adopted a more moderate and staged approach to future oil sands expansions due the low commodity price environment. Expanding existing projects and developing emerging projects will depend upon achieving further cost reductions as well as additional federal fiscal and regulatory certainty.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2016 is forecast to be between $325 million and $350 million. We plan to continue focusing on sustaining capital related to existing production as well as completing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Spending related to construction work on phase H was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase H has an initial design capacity of 30,000 gross barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrels per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2016 is forecast to be between $350 million and $375 million, focused on sustaining capital related to existing production and expansion phase F. We anticipate adding gross production capacity of 50,000 barrels per day from phase F in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Construction work on phase G was deferred in 2015 in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G has an initial design capacity of 50,000 gross barrels per day. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake in 2016 is forecast to be between $10 million and $20 million, focusing on phase A detailed engineering.

Emerging Projects

Capital investment for our new resource plays is forecast to be between $45 million and $55 million in 2016.

Depreciation, Depletion & Amortization

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

The following calculation illustrates how the implied depletion rate for our upstream assets could be determined using the reported consolidated data:

($ millions, unless otherwise indicated)	As at December 31, 2015
Upstream Property, Plant and Equipment	12,627
Estimated Future Development Capital	19,671
Total Estimated Upstream Cost Base	32,298
Total Proved Reserves (MMBOE)	2,546
Implied Depletion Rate ($/BOE)	12.69

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between $13.50 to $14.50 per BOE. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the first quarter of 2016, Oil Sands DD&A decreased $22 million primarily due to a combination of lower sales volumes and lower DD&A rates. The average depletion rate was approximately $11.55 per barrel compared with $11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake.

CONVENTIONAL

Our Conventional operations include dependable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a CO_2 enhanced oil recovery project in Weyburn, our heavy oil asset at Pelican Lake that uses polymer flood technology and emerging tight oil assets in Alberta. The established assets in this segment are strategically important for their long-life reserves, stable operations and diversity of crude oil produced. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

Significant developments that impacted our Conventional segment in the first quarter of 2016 compared with 2015 include:

- Crude oil and natural gas netbacks, excluding realized risk management activities, of $7.73 per barrel and $0.92 per Mcf, respectively;
- Crude oil production averaging 59,576 barrels per day, decreasing 19 percent, as an increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, and the sale of our royalty interest and mineral fee title lands business;
- Reducing our crude oil operating costs by $32 million or $1.62 per barrel;
- Generating Operating Cash Flow net of capital investment of $83 million, a decrease of 54 percent; and
- Recording impairment losses associated with our Northern Alberta cash generating unit ("CGU") of $170 million due to the decline in forward commodity prices.

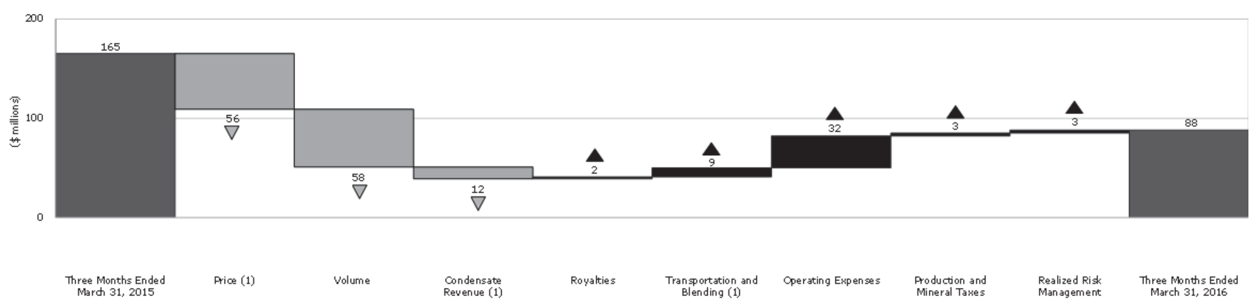
Conventional – Crude Oil

Financial Results

($ millions)	Three Months Ended March 31, 2016	2015
Gross Sales	**189**	315
Less: Royalties	**17**	19
Revenues	**172**	296
Expenses		
Transportation and Blending	**44**	53
Operating [(1)]	**78**	110
Production and Mineral Taxes	**2**	5
(Gain) Loss on Risk Management	**(40)**	(37)
Operating Cash Flow	**88**	165
Capital Investment	**37**	62
Operating Cash Flow Net of Related Capital Investment	**51**	103

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

Operating Cash Flow Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Pricing

Our average crude oil sales price decreased 26 percent to $29.82 per barrel, consistent with the decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	Three Months Ended March 31, 2016	Percent Change	2015
Heavy Oil	**31,247**	**(16)%**	37,155
Light and Medium Oil	**27,121**	**(23)%**	35,135
NGLs	**1,208**	**(11)%**	1,358
	59,576	**(19)%**	73,648

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,700 barrels per day in the first quarter of 2015.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential, the proportion of the cost of condensate recovered decreased.

Royalties

Royalties decreased primarily due to lower realized sales prices and a decrease in sales volumes partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business in 2015. For 2016, the effective crude oil royalty rate for our Conventional properties was 12.6 percent (2015 – 7.5 percent).

Crown royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. The Pelican Lake royalty calculation is based on net profits.

In the first quarter of 2016, production and mineral taxes decreased consistent with the decline in crude oil prices and due to the sale of our royalty interest and mineral fee title lands business in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $9 million. Blending costs declined due to lower condensate prices as well as a decrease in condensate volumes, consistent with lower production. In the first quarter, we recorded a $3 million (2015 – $3 million) write-down of our blended crude oil inventory to net realizable value as a result of the decline in crude oil prices through March and into April.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in the volumes moved by rail. We did not transport any volumes by rail in the first quarter of 2016 (2015 – 1,591 barrels per day).

Operating

Primary drivers of our operating expenses in the first quarter of 2016 were workforce, electricity, workovers, property taxes and lease costs. Operating expenses declined $32 million or $1.62 per barrel.

The per-unit decline was primarily due to:

- Workforce reductions;
- Lower chemical costs associated with reduced polymer consumption; and
- A decline in repairs and maintenance and workover costs as a result of focusing on critical activities and achieving operational efficiencies.

These decreases were partially offset by lower production volumes.

Operating Netbacks

($/bbl)	Heavy Oil 2016	Heavy Oil 2015	Light and Medium 2016	Light and Medium 2015
	Three Months Ended March 31,			
Price (1)	**25.99**	35.85	**34.36**	45.81
Royalties	**1.40**	2.34	**5.18**	3.56
Transportation and Blending (1)	**4.77**	3.42	**2.73**	2.88
Operating Expenses (2)	**13.98**	17.30	**16.34**	16.04
Production and Mineral Taxes	**-**	0.02	**0.82**	1.28
Netback Excluding Realized Risk Management (3)	**5.84**	12.77	**9.29**	22.05
Realized Risk Management	**7.98**	5.58	**7.90**	5.90
Netback Including Realized Risk Management	**13.82**	18.35	**17.19**	27.95

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $10.04 per barrel (2015 – $11.50). Our blending ratios range from approximately 10 percent to 16 percent.

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(3) The netbacks do not reflect non-cash write-downs of product inventory.

Risk Management

Risk management activities for the first quarter resulted in realized gains of $40 million (2015 – $37 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended March 31, 2016	2015
Gross Sales	**82**	122
Less: Royalties	**3**	2
Revenues	**79**	120
Expenses		
Transportation and Blending	**3**	5
Operating	**42**	47
Production and Mineral Taxes	**-**	-
(Gain) Loss on Risk Management	**1**	(10)
Operating Cash Flow	**33**	78
Capital Investment	**2**	4
Operating Cash Flow Net of Related Capital Investment	**31**	74

Operating Cash Flow from natural gas continued to help fund our Oil Sands segment.

Revenues

Pricing

In the first quarter of 2016, our average natural gas sales price decreased 25 percent to $2.31 per Mcf, consistent with the decline in the AECO benchmark price.

Production

Production decreased 12 percent to 391 MMcf per day due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 19 MMcf per day in the first quarter of 2015.

Royalties

Royalties increased as a result of additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business, partially offset by lower prices and production declines. The average royalty rate in the first quarter was 4.5 percent (2015 – 1.7 percent).

Expenses

Transportation

In 2016, transportation costs decreased as a result of lower production volumes.

Operating

Primary drivers of our operating expenses were property taxes and lease costs, and workforce. In the first quarter, operating expenses decreased by $5 million primarily due to lower workforce costs, and repairs and maintenance, offset by lower production volumes.

Risk Management

Risk management activities resulted in realized losses of $1 million in the first quarter of 2016 (2015 – gains of $10 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Capital Investment

($ millions)	Three Months Ended March 31, **2016**	2015
Heavy Oil	**10**	22
Light and Medium Oil	**27**	40
Natural Gas	**2**	4
Capital Investment [1]	**39**	66

(1) *Includes expenditures on PP&E and E&E assets.*

Capital investment in 2016 was primarily related to maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn. Capital investment declined in the current quarter primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

Drilling Activity

(net wells, unless otherwise stated)	Three Months Ended March 31, **2016**	2015
Crude Oil	**1**	5
Recompletions	**65**	34
Gross Stratigraphic Test Wells	**4**	-

Drilling activity in the first quarter of 2016 focused on natural gas recompletions performed to optimize production.

Future Capital Investment

We are taking a more moderate approach to developing our conventional crude oil opportunities due to the low commodity price environment. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

Our 2016 crude oil capital investment forecast is between $125 million and $150 million with spending plans mainly focused on maintaining and optimizing current production volumes.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

Conventional DD&A increased $60 million in the first quarter of 2016 as the decline in sales volumes and lower DD&A rates were more than offset by impairment charges. The average depletion rate decreased approximately 20 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined, in part, from an impairment charge of $184 million associated with our Northern Alberta CGU recorded at December 31, 2015 and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

We recorded impairment charges associated with our Northern Alberta CGU of $170 million due to the decline in forward commodity prices.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries.

Refinery Operations [1]

	Three Months Ended March 31, 2016	2015
Crude Oil Capacity [2] (Mbbls/d)	**460**	460
Crude Oil Runs (Mbbls/d)	**435**	439
Heavy Crude Oil	**241**	220
Light/Medium	**194**	219
Refined Products (Mbbls/d)	**460**	469
Gasoline	**229**	236
Distillate	**142**	144
Other	**89**	89
Crude Utilization (percent)	**95**	95

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity, based on 95 percent of the highest average rate achieved over a continuous 30-day period.

On a 100-percent basis, our refineries have total capacity of approximately 460,000 gross barrels per day of crude oil, excluding NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil, and capacity of 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows us to economically integrate our heavy crude oil production. Processing less expensive crude oil creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit. Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity.

Crude oil runs decreased slightly compared with 2015. Higher heavy crude oil volumes were processed due to the optimization of our total crude input slate, which reduces our feedstock costs. Refined product output decreased slightly as we completed planned and unplanned maintenance at our Wood River and Borger refineries in the first quarter of 2016. In the first quarter of 2015, a planned turnaround was completed at our Borger Refinery.

Financial Results

($ millions)	Three Months Ended March 31, 2016	2015
Revenues	**1,588**	2,096
Purchased Product	**1,428**	1,838
Gross Margin	**160**	258
Expenses		
Operating	**203**	177
(Gain) Loss on Risk Management	**(20)**	(14)
Operating Cash Flow	**(23)**	95
Capital Investment	**52**	44
Operating Cash Flow Net of Related Capital Investment	**(75)**	51

Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil, refinery configuration and the proportion of gasoline, distillate and secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through our refineries; and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In the first quarter of 2016, the decline in gross margin was primarily due to:

- Lower average market crack spreads, which decreased by approximately 41 percent, due to higher global refined product inventory and narrowing of the Brent-WTI differential; and
- An inventory write-down of $3 million related to our refined product inventory (2015 – $nil million).

The decrease in gross margin was partially offset by improved margins on the sale of our secondary products, such as coke, asphalt and sulfur, due to lower overall feedstock costs consistent with the decline in WTI, and weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar relative to the U.S. dollar in the first quarter of 2016, compared with 2015, had a positive impact of approximately $13 million on our refining gross margin.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In the first quarter of 2016, the cost of our RINs was $62 million (2015 – $53 million). The increase is consistent with the rise in the ethanol RINs benchmark price.

Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in 2016 decreased 18 percent from 2015, primarily due to a decline in sales prices, partially offset by an increase in purchased natural gas volumes.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2016 were labour, maintenance, utilities and supplies. Reported operating expenses increased compared with 2015 primarily due to weakening of the Canadian dollar relative to the U.S. dollar, partially offset by a decline in utility costs resulting from lower natural gas prices and no turnaround costs incurred in 2016.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended March 31, 2016	2015
Wood River Refinery	**36**	27
Borger Refinery	**14**	17
Marketing	**2**	-
	52	44

Capital expenditures in the first quarter of 2016 focused on the debottlenecking project at Wood River, capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives. Start-up of the Wood River debottlenecking project is anticipated in the third quarter of 2016.

In 2016, we expect to invest between $240 million and $290 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $9 million in 2016, primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, and the unrealized mark-to-market gains and losses on the long-term power purchase contract and interest rate swaps. In the first quarter of 2016, our risk management activities resulted in $149 million of unrealized losses (2015 – $145 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

($ millions)	Three Months Ended March 31, 2016	2015
General and Administrative [(1)]	**60**	71
Finance Costs	**124**	121
Interest Income	**(11)**	(11)
Foreign Exchange (Gain) Loss, Net	**(403)**	515
Research Costs	**18**	7
(Gain) Loss on Divestiture of Assets	**-**	(16)
	(212)	687

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2016 were workforce, office rent and information technology costs. General and administrative expenses decreased by $11 million primarily due to 2015 workforce reductions and lower information technology costs. Lower discretionary spending also contributed to the reduction of general and administrative costs.

We identified additional workforce reductions in the first quarter, which were largely implemented in early April. As a result, severance costs of approximately $17 million are expected to be recorded in the second quarter of 2016.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $3 million in 2016 compared with the same period in 2015 as weakening of the Canadian dollar relative to the U.S. dollar increased interest incurred on our U.S. dollar denominated debt.

The weighted average interest rate on outstanding debt for the first quarter was 5.3 percent (2015 – 5.2 percent).

Foreign Exchange

($ millions)	Three Months Ended March 31, 2016	2015
Unrealized Foreign Exchange (Gain) Loss	**(409)**	523
Realized Foreign Exchange (Gain) Loss	**6**	(8)
	(403)	515

The majority of unrealized foreign exchange gains resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was seven percent stronger at March 31, 2016 compared with December 31, 2015, resulting in unrealized gains of $409 million.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2016 was $17 million (2015 – $21 million).

Income Tax

($ millions)	Three Months Ended March 31, 2016	2015
Current Tax		
Canada	**(27)**	(86)
United States	**-**	-
Total Current Tax Expense (Recovery)	**(27)**	(86)
Deferred Tax Expense (Recovery)	**(190)**	(27)
	(217)	(113)

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions)	Three Months Ended March 31, 2016	2015
Earnings Before Income Tax	**(335)**	(781)
Canadian Statutory Rate	**27.0%**	25.2%
Expected Income Tax	**(90)**	(197)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(27)**	(11)
Non-Deductible Stock-Based Compensation	**2**	5
Non-Taxable Capital Losses	**(56)**	65
Unrecognized Capital Losses Arising From Unrealized Foreign Exchange	**(56)**	65
Adjustments Arising From Prior Year Tax Filings	**-**	(11)
Other	**10**	(29)
Total Tax	**(217)**	(113)
Effective Tax Rate	**64.8%**	14.5%

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and as a result, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

In the first quarter of 2016, we incurred losses, a portion of which of will be carried back to recover taxes previously paid in Canada. In the first quarter of 2015, the current tax recovery included the results of certain corporate restructuring transactions and a favorable adjustment related to prior years. The deferred tax recovery increased in the first quarter of 2016 as the benefit from a portion of current period losses was deferred to future periods.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. The effective tax rate differs from the statutory tax rate as it reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates and other tax legislation, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

Our effective tax rate differs from the statutory rate due to approximately $400 million of non-taxable foreign exchange gains.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended March 31, 2016	2015
Net Cash From (Used In)		
Operating Activities	**182**	275
Investing Activities	**(369)**	(643)
Net Cash Provided (Used) Before Financing Activities	**(187)**	(368)
Financing Activities	**(41)**	1,292
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**6**	(3)
Increase (Decrease) in Cash and Cash Equivalents	**(222)**	921

	March 31, 2016	December 31, 2015
Cash and Cash Equivalents	**3,883**	4,105
Committed and Undrawn Credit Facilities	**4,000**	4,000

Operating Activities

Cash from operating activities decreased in the first quarter of 2016 mainly due to lower Cash Flow, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,031 million at March 31, 2016 compared with $4,337 million at December 31, 2015.

We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

Capital investment declined in the current quarter primarily due to spending reductions in response to the low commodity price environment.

Financing Activities

Cash provided by financing activities decreased. In 2016, we paid dividends of $0.05 per share or $41 million. In the first quarter of 2015, cash from financing activities included net proceeds of $1.4 billion from our common share issuance, partially offset by dividend payments of $138 million.

Our long-term debt at March 31, 2016 was $6,113 million (December 31, 2015 – $6,525 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $412 million decrease in long-term debt is due to strengthening of the Canadian dollar relative to the U.S. dollar.

As at March 31, 2016, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flow from our crude oil, natural gas and refining operations to fund a portion of our cash requirements. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

The following sources of liquidity are available at March 31, 2016:

($ millions)	Amount	Term
Cash and Cash Equivalents	**3,883**	**Not applicable**
Committed Credit Facility (1)	**1,000**	**November 2017**
Committed Credit Facility	**3,000**	**November 2019**
U.S. Base Shelf Prospectus (2)	**US$5,000**	**March 2018**
Canadian Base Debt Shelf Prospectus (2)	**1,500**	**July 2016**

(1) *Extended to April 30, 2019, effective April 22, 2016.*
(2) *Availability is subject to market conditions.*

Committed Credit Facility

We have a $4.0 billion committed credit facility, with $1.0 billion maturing on April 30, 2019 and $3.0 billion maturing on November 30, 2019. Effective April 22, 2016, we extended the maturity date of the $1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at March 31, 2016, no amounts are drawn on our committed credit facilities.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

U.S. and Canadian Base Shelf Prospectuses

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018 and replaces the US$2.0 billion U.S. base debt shelf prospectus. In addition, we have a $1.5 billion Canadian base debt shelf prospectus, which will expire in July 2016.

As at March 31, 2016, there have been no issuances under either of the prospectuses.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill and asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	**March 31, 2016**	December 31, 2015
Net Debt to Capitalization [(1)] [(2)]	**16%**	16%
Debt to Capitalization	**34%**	34%
Net Debt to Adjusted EBITDA [(1)]	**1.3x**	1.2x
Debt to Adjusted EBITDA	**3.6x**	3.1x

(1) *Net Debt is defined as Debt net of cash and cash equivalents.*
(2) *Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.*

Over the long-term, we target a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 times to 2.0 times. At different points within the economic cycle, we expect these ratios may periodically be outside of the target range.

Debt to Capitalization remained consistent as the lower long-term debt balance, from the strengthening of the Canadian dollar relative to the U.S. dollar, was offset by the decrease in Shareholders' Equity. Debt to Adjusted EBITDA increased as a result of lower Adjusted EBITDA, primarily due to a decline in Cash Flow from lower commodity prices, partially offset by the lower long-term debt balance.

Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 16 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at March 31, 2016	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**43,811**	**34,141**
Other Stock-Based Compensation Plans	**8,043**	**1,566**

Contractual Obligations and Commitments

We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements and operating leases on buildings. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

During the first quarter of 2016, net transportation commitments decreased by approximately $1 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement, and should help align our future transportation requirements with our anticipated production growth. As at March 31, 2016, total transportation commitments were $26 billion.

As at March 31, 2016, there were outstanding letters of credit aggregating $211 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of our 2015 annual MD&A. A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2015.

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We continue to be exposed to the risks identified in our 2015 annual MD&A.

The following provides an update on our risks related to commodity prices, royalty regimes and climate change.

Commodity Price Risk

Fluctuations in commodity prices and refined product prices impacts our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 18 and 19 to the interim Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	Three Months Ended March 31,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(164)**	**118**	**(46)**	(128)	119	(9)
Natural Gas	**-**	**-**	**-**	(12)	11	(1)
Refining	**(4)**	**3**	**(1)**	(14)	9	(5)
Power	**3**	**(14)**	**(11)**	3	6	9
Interest Rate	**-**	**42**	**42**	-	-	-
(Gain) Loss on Risk Management	**(165)**	**149**	**(16)**	(151)	145	(6)
Income Tax Expense (Recovery)	**43**	**(41)**	**2**	40	(37)	3
(Gain) Loss on Risk Management, After Tax	**(122)**	**108**	**(14)**	(111)	108	(3)

In the first quarter of 2016, we recorded realized gains on crude oil risk management activities, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil financial instruments primarily due to the realization of settled positions and changes in market prices. Unrealized losses were recorded on our interest rate hedge positions due to decreases in benchmark interest rates.

Risks Associated with Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Credit Policy.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus if commodity price increases. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

Royalty Regime Risk

The Governments of Alberta and Saskatchewan receive royalties on the production of crude oil and natural gas from lands where they own the mineral rights. The Government of Alberta released its Royalty Review Advisory Panel Report on January 29, 2016 (the "Review"). The Review recommends no changes to the existing oil sands royalty structure. It also calls for a modernization of Alberta's conventional oil and gas royalty regime and the Government of Alberta is currently consulting with industry to finalize details of the royalty calculations. The Review further recommends that all wells drilled before 2017 be grandfathered under the current rules for a 10 year period. The Government of Alberta has accepted the recommendations and is expected to adopt them in the spring of 2016, to take effect in 2017.

These changes to the Alberta provincial royalty structure are not anticipated to materially impact Cenovus's financial condition; however, any future changes to the royalty and mineral tax regimes in provinces in which we operate, could have a significant impact on Cenovus's financial condition, results of operations, cash flows, and future capital expenditures.

Climate Change Risk

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas emissions ("GHG") and other air pollutants. In November, 2015, the Government of Alberta announced its climate leadership plan (the "CLP") highlighting four key strategies that will be implemented to address climate change. Legislation to implement the CLP is anticipated to be brought forward in the spring of 2016, to take effect in 2017.

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of GHG emitting facilities. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners from 12 percent to 15 percent in 2016 and 20 percent in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The SGER amendments increased the price for such credits from $15 per tonne to $20 per tonne for 2016 and $30 per tonne in 2017.

In December 2015, Canada and other countries that are members of the United Nations Framework Convention on Climate Change signed the Paris Agreement on climate change, which aims to limit the rate of global warming and contemplates developing carbon markets by 2020. The Government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016. We are unable to predict the impact of the Paris Agreement on our operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on our financial condition, results of operations, and cash flow.

If comprehensive GHG regulation is enacted in Alberta or any jurisdiction in which we operate, including in relation to the CLP, the Paris Agreement, or the amendments to the SGER, we may incur increased compliance costs or actions, loss of markets, permitting delays, and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses and reduce demand for crude oil, natural gas and certain refined products. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies during the three months ended March 31, 2016. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the three months ended March 31, 2016.

Future Accounting Pronouncements

A description of additional accounting standards and interpretations that will be adopted in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2016 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

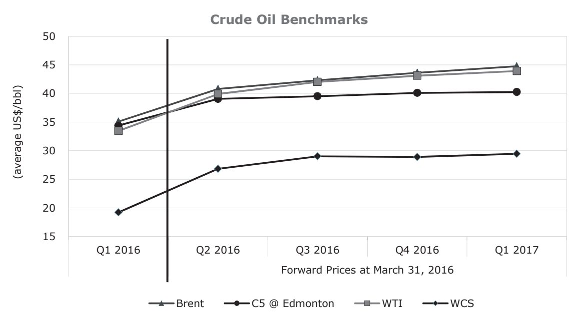
OUTLOOK

We expect 2016 will be a very challenging year for our industry and our business. Maintaining our financial resilience remains our top priority, while maintaining safe operations. Our 2016 guidance reflects reduced capital, operating, general and administrative spending.

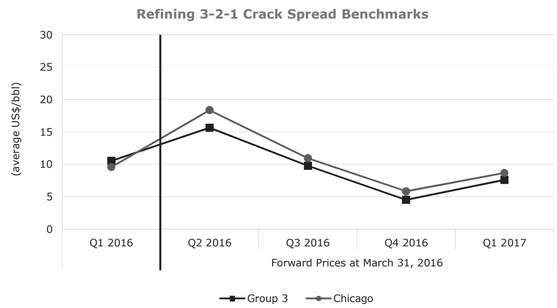
The following outlook commentary is focused on the next 12 months.

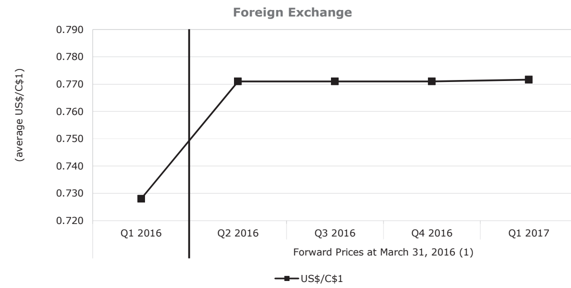
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:



- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment and the pace of growth in global demand. Overall, we expect crude oil price volatility and a modest price improvement in 2016. Anticipated global supply declines, combined with annual increases in demand growth, should support prices in the second half of the year, constrained by the need to draw down surplus crude oil inventories and re-entry of Iranian crude oil into markets. We continue to anticipate supply declines from North American producers as a result of the significant reductions in capital spending. The low crude oil price environment also serves to help boost global economic momentum. However, we believe that economic uncertainty in China may continue and we expect it to impact emerging market demand;
- We expect the Brent-WTI differential to remain narrow now that the U.S. is exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We also expect that the WTI-WCS differential will remain wide due to additional Canadian supply growth and declining U.S. light tight oil supply. However, substantially wider differentials are unlikely due to excess rail capacity.





(1) Refer to the foreign exchange rate sensitivities found within our current guidance available at cenovus.com.

Refining crack spreads in 2016, as forecasted at March 31, 2016, are expected to strengthen late in the second quarter due to higher seasonal demand for refined products and then decline in the second half of the year.

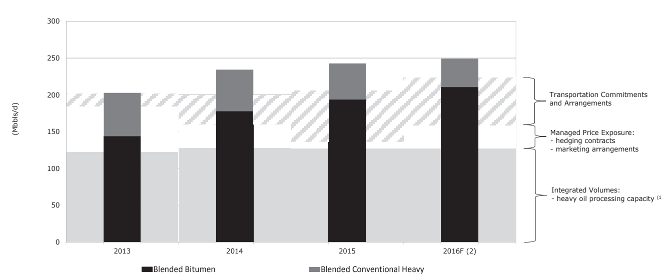
Weak natural gas prices in the first quarter of 2016 reflect lower demand due to warmer than normal winter temperatures and above average storage levels. Pricing is anticipated to improve throughout 2016 due to lower supply growth, although price escalation should be limited by the continued need for coal-to-gas substitution in the power sector.

The average foreign exchange forward price expected over the next 12 months is US$0.771/C$. Overall, we expect the Canadian dollar to remain relatively weak which will have a positive impact on our revenues and Operating Cash Flow.

Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian congestion. While we expect to see volatility in crude oil prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Congestion



(1) Excludes additional 18,000 bbls/d heavy oil capacity expected as a result of the Wood River debottlenecking project (expected in the second half of 2016).
(2) Expected gross production capacity.

Key Priorities for 2016

Maintain Financial Resilience

Maintaining our financial resilience continues to be our top priority, while maintaining safe operations. At March 31, 2016, we had $3.9 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 16 years, with no debt maturing until the fourth quarter of 2019. Although we have a strong balance sheet, we plan to undertake additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs.

Attack Cost Structures

We will continue to focus on reducing our cost structure. We anticipate capital investment in 2016 of $1.2 billion to $1.3 billion, a reduction of $200 million to $300 million from our original 2016 budget announced in December 2015. We are targeting $200 million of further savings in operating, general and administrative and compensation costs. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure, and maximize the strengths of our functional business model.

Disciplined and Value-added Growth

We are committed to exercising capital discipline. We will consider expanding existing projects and developing emerging opportunities only when we believe we will generate attractive potential returns for shareholders. Although we have some of the needed fiscal and regulatory clarity at the provincial level, additional certainty around federal fiscal and regulatory regimes, commodity prices and our ability to sustain cost reductions is required. We will only commit to project reactivation if it does not undermine the strength of our balance sheet.

ADVISORY

Oil and Gas Information

The estimates of reserves data and related information were prepared effective December 31, 2015 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2016 price forecast. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2015.

Barrels of Oil Equivalent – Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "capacity", "could", "should", "focus", "goal", "outlook", "proposed", "potential", "may", "schedule", "on track", "strategy", "forward", "opportunity" or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules; projected future value; projections for 2016 and future years; our future opportunities for oil development; forecast operating and financial results; targets for our Debt to Capitalization and Debt to EBITDA ratios; planned capital expenditures, including the timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves; broadening market access; expected capacities, including for projects, transportation and refining; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost savings and sustainability thereof; future impact of regulatory measures; forecast commodity prices and expected impact to Cenovus; future use and development of technology, including impacts thereof; potential impacts to Cenovus of various risks, including those related to derivative financial instruments, royalty regimes and climate change and associated regulations, and the potential effectiveness of our risk management strategies; and our focus on driving shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: assumptions inherent in Cenovus's 2016 guidance, available at cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2016 guidance, (as updated on February 11, 2016,), available at cenovus.com, assumes: Brent of US$52.75/bbl, WTI of US$49.00/bbl; WCS of US$34.50/bbl; NYMEX of US$2.50/MMBtu; AECO of $2.50/GJ; Chicago 3-2-1 crack spread of US$12.00/bbl; and an exchange rate of $0.75 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net debt to capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated business; reliability of our assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; risks associated with the fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; changes in our labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the period ended December 31, 2015, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
BOE	barrel of oil equivalent	GJ	gigajoule
BOE/d	barrel of oil equivalent per day	AECO	Alberta Energy Company
MBOE	thousand barrel of oil equivalent	NYMEX	New York Mercantile Exchange
MMBOE	million barrel of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend	TM	trademark of Cenovus Energy Inc.